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BY EMAIL and RESS

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Our File: EB20180028

Ontario Energy Board
2300 Yonge Street
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Toronto, Ontario
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Attn: Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: EB-2018-0028 – Energy+ Inc. – SEC Final Argument

We are counsel to the School Energy Coalition ("SEC"). Enclosed, please find SEC's Final Argument on the unsettled issues.

Yours very truly,
Shepherd Rubenstein P.C.

Original signed by

Mark Rubenstein

cc: Wayne McNally, SEC (by email)
Applicant and interested parties (by email)

EB-2018-0028

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15 (Schedule B);

AND IN THE MATTER OF an application to the Ontario Energy Board by Energy+ Inc. pursuant to Section 78 of the *Ontario Energy Board Act* for approval of its proposed distribution rates and other charges, effective
January 1, 2019.

FINAL ARGUMENT OF THE

SCHOOL ENERGY COALITION

A. Overview

1. Energy+ Inc. ("Energy+") has filed an application for approval of distribution rates effective January 1, 2019.

2. Most of the application was settled by way of a Settlement Proposal filed with the Board on December 12 2018. A number of issues remained unsettled relating to the Energy+ proposal for an Advanced Capital Module ("ACM"), certain deferral and variance accounts, and all issues related to cost allocation and rate design, including the request to approve a standby charge.

3. This has been an unusually complicated proceeding for a distributor of Energy+'s size. The proceeding had multiple rounds of interrogatories, a technical conference, and the filing of both additional evidence from Energy+ and intervenor evidence from Toyota Motor Manufacturer Canada Inc. ("TMMC").

4. This is the final Argument of the School Energy Coalition ("SEC") on the unsettled issues.

B. Advanced Capital Module (Southworks Facility)

5. Energy+ seeks approval of an ACM for its proposed $8.1M Southworks facility, expected to go into-service in 2022.[1] The Southworks facility would house Energy+'s administrative staff, and is part of a larger Facilities Business Plan ("Facilities Plan") that includes a new shared operations

[1] Updated Evidence, p.2

centre with Brantford Power Inc. ("BPI"), the renovation of its existing Bishop Street facility, the sale of its current Dundas St. property, and the end of its lease for the Thompson St. facility.[2] Energy+ has brought forward the project as an ACM instead of as an ICM, as it wishes to have the regulatory certainty regarding its ability to recover costs before it expends the significant funds. [3]

6. SEC submits that the evidence demonstrates that the project meets the ACM requirements of materiality and need, but Energy+ has not met its onus to demonstrate that the Southworks facility is prudent. The Board should deny the ACM but allow Energy+ to reapply if it is able to bring forward evidence to demonstrate that the Southworks facility is the best option available for its proposed administrative offices.

7. ***Project.*** Energy+'s evidence is that due to challenges related to the age and condition of its various buildings, the merger with Brant County Power, and the operational needs of its staff, significant expansion and renovation of its facilities are needed. To determine what the best approach would be, it undertook a number of third-party assessments in 2013 to 2015 and landed on the current set of proposals which makes up its integrated Facilities Plan.[4]

8. One aspect of that Facilities Plan was the need for centralized and more appropriate administrative space to act as a head office in Cambridge.[5] The evidence was that Energy+ was approached by a third-party developer, who wanted Energy+ to act as the anchor tenant in a new mixed-use development which includes commercial shopping properties and two large condominium towers.[6] In return, Energy+ was given the ability to acquire a portion of an existing building for $1.[7] When the application was originally filed, the cost to renovate the building for its purposes was $5M, with an in-service date of 2020.[8] By the late fall, the cost has already ballooned by 62% to $8.1M, and the project delayed until 2022.[9]

[2] Ex.2, p.25; Exhibit 2, Appendix N; Interrogatory Response 2-SEC-27b), Appendix

[3] Technical Conference Transcript, p.11

[4] Exhibit 2, Appendix N, p.1027-1029

[5] Exhibit 2, Appendix N, p.1025

[6] Transcript, Vol.1, p.32; Interrogatory Response 2-SEC-27b), Appendix, p.435;

[7] Transcript, Vol.1, p.58-59

[8] Transcript, Vol.1, p.56-57; Updated Evidence, p.2

[9] *Ibid*

9. SEC submits that there are numerous concerns about the prudence of the proposed Southworks Facility.

10. ***Unreliable Class Estimate.*** There is little reason to have much faith in the accuracy of the updated forecast of $8.1M, considering the past history of the project. The new forecast is based on a Class C estimate, which has a range of accuracy of +/- 20% ($6.58M-$9.7M).[10] The problem is that the previous forecast of $5M, based on a Class D estimate, was entirely incorrect and the error was more than double the accuracy range of +/-30% at 62%.[11] In fact, when one looks at only the construction cost estimate, as opposed to other aspects of the broader project, the increase is even higher.[12] This is a very significant increase in costs that has not been adequately explained, and should give the Board little assurance of the reliability of the current forecast, which is only Class C.

11. ***No Analysis Undertaken to Demonstrate Southworks Was Best Option.*** Energy+ determined based on its analysis that the best option was a dedicated administration facility. Yet, it took no analysis to determine if the current proposal for the Southworks facility was the best option for a dedicated administrative facility. It did not retain the help of a real estate professional to look at other options for a purely administrative building, either to purchase or lease.[13] Mr. Miles, on behalf of Energy+, testified that they did not do this because a) there is not a lot of real estate in Cambridge, and b) they were going to tender out the material and construction costs to ensure the costs are prudent. [14]

12. Neither rationale is sufficient. First, Energy+ is not a real estate company, and in preparing to spend millions of dollars to purchase and construct a new building, it was incumbent upon them to do the necessary due diligence to determine that the specific site it purchased was the most cost effective solution. Without that information, not only does Board unableable make that assessment in assessing the application, but neither did Energy+ when it decided to go forward with Southworks facility. While having a purely administrative building may be prudent in the context of the overall Facility Plan, there is no evidence on the record to justify that the Southworks facility itself is the

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[10] Transcript, Vol.1, p.65, 72-73

[11] Transcript, Vol.1, p. 73

[12] Transcript, Vol., p.72

[13] Transcript, Vol., p.49-50

[14] Ibid

prudent option. Second, the fact that Energy+ will put the construction out for competitive bid is not relevant to the question of the prudence of the Southworks option. At best it is simply an indicator that the costs to construct the project, based on the specific site and design are reasonable, it reveals nothing about the prudence of the site and design itself.

13. ***Energy+ Costs Above Benchmark.*** Based on the forecast costs of the project, the cost per square foot appears to be significantly higher than other similar projects. In its evidence, Energy+ provided benchmarking information regarding the cost of its entire Facilities Plan, compared against new builds or purchase/renovations undertaken by other distributors.[15] The problem with Energy+'s analysis is that within its costs it includes the renovation of its existing Bishop Street facility. A renovation of an existing facility used for distribution services is a fraction of the cost of a new facility, and is entirely dissimilar to those of the comparator distributor projects that Energy+ selected. When that facility is removed, and only the Southworks and Garden Street facility are included, Energy+'s forecast costs per square foot are significantly *higher* than the comparators. Since the Garden St. facility is not before the Board at this time, and the benchmark facilities are all dual administrative and operations facilities, it is not clear why the total cost is so much higher, but it is a concern that warrants requiring further information from Energy+, before approving the cost consequences of the project.

14. In its Argument-in-Chief, Energy+ puts great emphasis on its comparative advantage when comparing square foot per FTE.[16] SEC accepts that on this metric, Energy+ is lower, but that only shows that the size of the property is more appropriate, not the cost of the property.

	Energy + (Entire Facilities Plan)	Energy+ (Southworks & Garden St.)	Energy + (Southworks)		Waterloo North Hydro	InnPower	Milton Hydro	PUC Distribution Inc.
Year of Occupancy	2022/22/24	2020/22	2022		2011	2015	2015	2012
Function	Admin & Ops	Admin & Ops	Admin		Admin & Ops	Admin & Ops	Admin & Ops	Admin & Ops
Type	Purchase/ Refubish	Purchase/ Refubish	Purchase/ Refurbish		Custom Build	Custom Build	Purchase/ Refubish	New Build
Capital Cost	14,500,000	$12,500,000	$8,100,000		$26,682,000	$10,896,704	$12,524,798	$23,000,000
Square Footage	88,243	35,143	21,892		105,000	36,172	91,872	110,382
Capital Cost/Square Footage	*$164.32*	*$355.69*	*$370.00*		*$254.11*	*$301.25*	*$136.33*	*$208.37*
Source: Response to SEC TCQ-5								

[15] Exhibit 2, p.1024; Updated Evidence, p.11-13

[16] Argument-in-Chief, para 40-41

15. ***Energy+ Did Not Select the Construction Management or Architectural Firm***. Energy+ did not select the architectural or the construction management firms, who are responsible for the design and the cost estimates, by way of a competitive procurement process. [17]In fact, it is not clear if Energy+ had any involvement in their selection. The evidence is that they were used, solely because they were used by the developer in the larger development process. Due to this, it is not clear whether their interest is entirely aligned with Energy+, as oppose to with the developer.

16. ***Summary.*** Energy+ has not met its onus to determine that the proposed Southworks project is prudent. The Board should deny the ACM on this basis. With that said, there is no evidence that the project is necessarily imprudent, and due to the need for some solution to its administrative space needs, Energy+ should be allowed to apply again once it has undertaken an appropriate verifiable assessment that the Sourthworks option is the most appropriate. Since Energy+ is already planning to bring forward a joint incremental capital module application with BPI for the proposed Garden St. facility[18], it can undertake the necessary work and file that additional evidence with that application. This would allow Energy+ to have a decision from the Board before much of the work is underway so as to still have certainty regarding the project.

C. Deferral And Variance Accounts

OEB Cost Assessment

17. Energy+ seeks recovery of Account 1508 – OEB Cost Assessment Account of $174,000 for the balances attributable to the years 2016 and 2017.[19]

18. The OEB Cost Assessment account was established on a generic basis by the Board by letter dated February 9, 2016, in response to the revision of the methodology used to apportion its costs

[17] Transcript Vol 1, p.57-58

[18] Settlement Proposal, December 12 2018, p.17:

> Energy+ also agrees to withdraw its request for 2020 Advanced Capital Module funding for its proposed Garden Avenue facility in Brantford, which will be a shared facility with Brantford Power Inc. Energy+ agrees with the supporting Parties noted below that it would be more efficient for the Board to consider the entire Garden Avenue facility at the same time and to reduce the possibility of inconsistent decisions. The supporting Parties noted below expect that Energy+ will submit an Incremental Capital Module request, together with a request to dispose the gain on sale of the Paris facility, concurrently with Brantford Power Inc.'s Incremental Capital Module application.

[19] Ex.9, p.30

under section 26 of the *Ontario Energy Board Act*.[20] Since it was the Board's view that the new methodology "may result in material shifts in the allocation of costs", it created a generic variance account to capture the difference between the cost assessment amounts built into rates and the cost assessments that will result from the application of the new model.[21]

19. The creation of this generic account was not meant to ensure that all balances would be recoverable, no matter the individual magnitude for a given regulated entity. The Board's letter was clear that "regulated entities are reminded that, in the normal course, any disposition of deferral and variance account balances must meet any OEB default or company-specific materiality thresholds".[22] This interpretation has been subsequently confirmed by the Board.[23]

20. Energy+ confirmed that its annual materiality threshold is $250,000.[24] The principal balances for amounts in 2016 of $70,507 and 2017 of $99,102 are both well below the Energy+ materiality threshold.[25] On that basis, since the annual amounts are not material, the Board should deny clearance of the balances of this account for 2016 and 2017.

Monthly Billing

21. Energy+ is seeking recovery of a total of $416,346 for costs in 2016 and 2017 for the incremental costs related to the Board's requirement that all distributors move to monthly billing, for the former Cambridge North Dumfries ("CND") service territory. In CND's 2015 IRM application, the Board approved the deferral account to record the incremental costs net the associated savings, such as improved cash flow and a reduction in bad debt.[26]

22. SEC does not take issue with the costs included in the account, only the calculation of the benefits. Energy+ has estimated the cash flow benefits related to the transition as the incremental

[20] OEB Letter, Revisions to the Ontario Energy Board Cost Assessment Model, February 9, 2016 <https://www.oeb.ca/oeb/_Documents/Corporate/Letter_Notice_of_Change_to_CAM_20160209.pdf>

[21] *Ibid*

[22] *Ibid*, p.2

[23] See *Decision and Order* (EB- EB-2018-0105 – Union Gas Ltd), November 26 2018, p.11-13

[24] Transcript Vol.1, p.89; Ex.1, p.164

[25] Ex.9, p.30

[26] *Decision and Rate Order* (EB-2015-0057 - CND), March 17 2016, see Schedule C

interest increase that would have been generated from the increase in cash flow.[27] SEC disagrees with this approach.

23. As the Board is aware, for rate-making purposes, a distributors cash flow needs are funded by applying a percentage of an amount for working capital to the rate base where it earns its weighted average cost of capital.[28] The working capital amount is determined by applying a working capital percentage, which attempts to measure the net lag in expenses to revenues, to the distributor's OM&A, property taxes and cost of power .This may or may not be an accurate reflection of the working capital a given distributor actually does need to manage its cash flow, but it is how that cost is included in rates, including Energy+ [29]

24. SEC submits the appropriate way to measure the cash flow benefit of moving to monthly billing is to determine what the change in working capital would be compared to that built into the rates. This ensures the cash flow 'benefit' is calculated on a similar basis to cash flow 'costs'.

25. Complicating matters is that when asked to provide the working capital savings, Energy+ responded by stating that it "has not done a lead lag study or any other analysis to calculate any working capital savings from the former CND in 2017".[30] Since Energy+ has not done the analysis, SEC has attempted to estimate the impact on the revenue requirement of moving all former CND customers to monthly billing in late 2016. In its 2016 cost of service application, CND used the then Board default value of 13%, to determine the working capital.[31] The problem with the 13% default value is the Board never provided a breakdown of how the amount was calculated.

26. To determine the impact, SEC has used the analysis the Board used in determining that the revised default value of the working capital allowance would be 7.5%[32]. Isolating the service lag/period which reflects the billing period calculation, if all customers were on bi-monthly billing

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[27] Updated Evidence, p.29

[28] Transcript Vol.1, p.81;OEB Letter Re: Allowance for Working Capital for Electricity Distribution Rate Applications, June 3 2015; K.1.5, p.19

[29] Transcript Vol.1, p.81

[30] Interrogatory Response 9-SEC-42; K1.4, p.4

[31] Response to Technical Conference Question SEC-10(a); K1.5, p.11

[32] OEB Letter Re: Allowance for Working Capital for Electricity Distribution Rate Applications, June 3 2015, Appendix A; K.1.5, p.22

versus monthly billing, that represents a 4.2% change in the total working capital allowance.[33] That number needs to be further adjusted to reflect the fact that only residential and some GS<50 customers were ever on bi-monthly billing.[34] Mr. Molon testified on behalf of Energy+ that the gross billings, for customers who transitioned to monthly billing, represented approximately 30% of the total amount billed.[35]

27. Based on this, SEC estimates the change in the working capital allowance related to the move to monthly billing to be approximately 1.26% of the working capital allowance. Considering that the CND 2014 revenue requirement included $1,489,594 for working capital based on 13% working capital allowance, a reduction of 9.6% (1.26%/13%) would result in an annual reduction of $143,001. Since the evidence is that customers began moving to monthly billing in late 2016, SEC has pro-rated the 2016 amount using the same time period as Energy+ (October-December). [36]

Monthly Billing Principal Balance		
	2016	**2017**
Energy+ Costs	$132,268	$365,718
Working Capital Savings	($35,750)	($143,001)
Recoverable Amount	***$96,518***	***$222,717***

28. SEC submits the appropriate recoverable amount is $96,518 for 2016 and $222,717 in 2017, plus the applicable DVA carrying charges.

LRAMVA

29. TMMC witnesses during the oral hearing appeared to question whether the Board Loss Revenue Adjustment Mechanism ("LRAM") was appropriate as it applied to it. Ms. Collis testified that TMMC found unfair that Energy+ lost revenue as a result of the TMMC's LDG facility it recovered from the rate class that was the cause.[37] For TMMC this means that for its LDG facility, the lost revenue would be recovered from the Large Use class or if successful, its own separate rate class. TMMC believes this is unfair.

[33] K1.5, p.23

[34] Transcript Volume 1, p.87

[35] Transcript Volume 1, p.88

[36] Argument-in-Chief, para 111

[37] Tr.2, p.42-43

30. SEC submits the Board should approve Energy+'s LRAM Variance Account ("LRAMVA") disposition methodology as proposed for two reasons. First, the policy on recover of the LRAMVA is well established and has been applied consistently to all distributors and all rate classes for years.[38] While SEC understands TMMC's complaint, the same could be said for all other customers and rate classes who engaged in conservation measures.[39] For example, schools have been early adopters in conservation and are disproportionately paying through the LRAM, the impact of conservation measures adopted by customers who are relatively late adopters. Second, it should be noted that LRAM only recovers the impact of approved conservation measures not built into distribution rates. It does not recover all other TMMC avoided costs due to its LDG facility, such as the much more significant commodity costs. TMMC is still significantly better off financially as a result of constructing its LDG facility.

D. Cost Allocation And Rate Design

Standby Charge

31. Energy+ has proposed the implementation of a standby charge for all customers in the GS>50, GS>1000, and Large Use rate classes who have load displacement generation ("LDG"). A standby charge is meant to capture the cost to Energy+, of being ready to provide a backup service when the load displacement generation is not generating, in full or in part. SEC submits that the proposed standby charge should not be approved at this time because, a) the Board is well advanced in a generic process to implement a Capacity Reserve Charge ("CRC") that would protect Energy+, b) the proposed structure would penalize customers who implement conservation and other efficiency measures, and c) a charge that requires negotiation between a customer and a distributor is only just and reasonable if the expectations are clear and the Board is the final arbitrator of the amount.

32. ***Energy+ Proposal.*** Energy+'s proposal is that the standby charge would be equal to the approved volumetric distribution rate and applied to the difference between the customer's monthly peak demand and that of a contracted demand level, called the contracted capacity.[40] The level of a

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[38] See LRAMVA WorkForm

[39] TMMC's LDG Facility was undertaken as part of the IESO's Process and System Upgrade Initiative (Transcript Vol 1, p.24-25) which is considered a program eligible for LRAM. See *Report of the Ontario Energy Board Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs* (EB-2016-0182), May 19, 2016, p.5

[40] Exhibit 7, p.14-16

contracted capacity for any given customer with load displacement generation would be determined by way of a negotiation between the customer and Energy+. While it may be styled as a negotiation, if the customer does not agree with Energy+, there is no neutral third-party who can make the determination. The dispute resolution process is simply an escalation within Energy+ management, and finally, the customer could seek non-binding advice from Board Staff.[41] There is also little guidance for how the contracted capacity should be determined. Energy+ has simply provided a long list of factors that should be considered.[42]

33. As the Board is aware, the matter of standby rates is something the Board is currently considering as part of its Rate Design for Commercial and Industrial Consultation ("C&I Consultation").[43] After years of consultation and discussion, Board Staff has recently released a report that proposes a CRC which would serve the same purpose as a standby charge. For most customers, the CRC would be determined on a more objective basis by charging the distribution volumetric rate on the technology specific capacity factor of the generators nameplate capacity.[44] If this approach is adopted by the Board in some form, then there would be no need for those customers to be required to negotiate with their distributor. For customers with demands over 5MW, there would be some room to negotiate the rate, depending on how they run the generator and recognition that they have this capability since they are "very sophisticated about their energy use".[45]

34. The asymmetry of bargaining power between an individual GS>50, or even GS>1000 customer, and Energy+, is significant. Most customers do not understand the intricacies of an appropriate contracted capacity, based on their specific load profile and LDG type. If set at a level anywhere near the nameplate capacity[46], they will be overpaying and Energy+ will get a significant windfall.

[41] 7-SEC-39b; K1.5, p.32

[42] 7-SEC-40(a); K1.5, p.32

[43] See EB-2015-0043

[44] Staff Report to the Board Rate Design for Commercial and Industrial Electricity Customers Rates to Support an Evolving Energy Sector (EB-2015-0043), February 21, 2019, p.41-43: K1.5, p.43-45

[45] *Ibid*, p.44-45; K1.5, p.46-47

[46] By way of example, the Board Staff reports has set the capacity factor for solar generation at 10% of the name plate capacity to recognize that at a customer's monthly peak only a fraction for the nameplate capacity is used.

35. Under the Energy+ approach, a customer will be required to pay the standby charge if the reduction in demand is below the contract capacity, even if it is caused in part by factors that have nothing to do with LDG. For example, if a customer with LDG also undertakes new energy efficiency or conservation measures, or simply reduces their use, they will be charged the standby rate for their actual peak demand below the contracted amount. For customers without LDG, they are not required to pay a standby charge or any other costs for reducing demand through conservation measures or by making consumption decisions.

36. ***Pollock Approach***. TMMC's expert has proposed a very different approach to the design of a standby charge. Mr. Pollock proposes a two-party standby charge. First, a customer would be charged a contract volumetric rate that would be applied monthly to a negotiated contract amount, regardless of the actual use of any standby service. This cost would reflect what Mr. Pollock calls local facilities, which are similar to customer specific facilities.[47] Second, a customer would be charged a daily volumetric rate that would be applied to the incremental demand in the month when a generation unit is out of service. The daily rate could only ever be applied during the weekday (i.e. peak period of the month) and is designed to recover the shared facilities, assuming the outage lasted during all peak days in the month.[48]

37. There are significant problems with Mr. Pollock's proposed standby charge.

38. Mr. Pollock developed his proposal for TMMC.[49] He was only asked to determine how it would be applied to customers of all other rate classes during the interrogatory process.[50] As it became apparent during the oral hearing, there would be significant practical challenges for Energy+ to adopt his two-part rate methodology for other customers, whose LDG facilities are orders of magnitudes smaller than the TMMC facilities. For example, to determine when the daily volumetric rate should be applied, the information that Energy+ would "need to know is whether an outage occurred and what was the effect of that outage in terms of the additional load placed on the system,

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[47] Updated Written Evidence of Jeffrey Pollock (J. Pollock Incorporated) on behalf of Toyota Motor Manufacturing Canada Inc., February 15, 2019 ["Pollock Report (Updated)"], p.26

[48] Pollock Report (Updated), p.28,30

[49] Transcript Vol.2, p.70

[50] Interrogatory Response SEC-TMMC-3; Technical Conference Transcript, p.87; JTC.1.9

if any."[51] This admittedly "after-the-fact analysis" may be able to be done for a large LDG facility like TMMCs, but it is not clear how it could be done for potentially dozens of small scale facilities installed for net-metering. [52]

39. When asked how this analysis could be undertaken for a small scale rooftop solar facility, such as these that schools are increasingly undertaking, Mr. Pollock could not provide a good answer, and recognized "[t]hat would be challenging".[53] The problem is, for many customers who may install LDG facilities it could never be done. This is because what would be required under Mr. Pollock's proposal is for Energy+ to know at peak times how much output the generator is producing.

40. It is possible for TMMC since its LDG facility is separately metered.[54] For most customers with small scale LDG facilities that would attract a standby rate, their generation is not separately metered. All Energy+ knows is the customer's load *net* of generation.

41. A significant concern that SEC has with Mr. Pollock's methodology for the proposed standby charge is, what he considers local facilities versus shared costs for the purposes of designing the contract volumetric versus daily volumetric rate. In his initial evidence, Mr. Pollock used the directly assignable costs or costs that are allocated on a non-coincident peak basis as shared facilities for TMMC.[55] This changed in his updated evidence, where only the directly assigned costs, the feeders and meters, were considered local facilities.[56] For example, Mr. Pollock has treated poles, which are pooled asset class for all customers, as a shared facility for the purposes of TMMC, but a local facility for the GS>50 rate class.[57] The reason for this appears to be because Mr. Pollock has not done any analysis regarding which of Energy+ facilities should be considered local, as opposed to shared, for any other class but the proposed TMMC class.[58]

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[51] Transcript Vol 2, p.74-75

[52] *Ibid*

[53] Transcript Vol 2, p.75

[54] Transcript Vol. 2, p.75

[55] Written Evidence of Jeffrey Pollock (J. Pollock Incorporated) on behalf of Toyota Motor Manufacturing Canada Inc., September 27, 2018 ["Pollock Report (Original)"], p.50

[56] Pollock Report (Updated), p.27

[57] *Ibid.*, p.29

[58] TMMC Responses Clarification Interrogatories 2-VECC-15.1

42. Mr. Pollock has been unable to provide a set of clear criteria that can be applied when allocating an asset or cost as either local or shared.[59] Since the contract volumetric rate, which is to recover local costs, is charged to customers regardless of their actual use of the standby service, the fewer costs categorized as local, the less the LDG customer would have to pay. Fairness between a utility and customers, and amongst customers', demands that workable and simple criteria be set out. As Mr. Pollock recognizes, more work would be needed. He testified that "you would have to do an analysis of the distribution system to further determine what portion, say, of the primary and secondary networks really are serving specific customers and therefore should be considered a local cost, as opposed to facilities that are more, you know, serving the nature of all customers, which would be a shared cost."[60]

43. SEC notes there are other issues regarding Mr. Pollock's approach. For example, the basis of the methodology behind the daily volumetric rate concept is that there is a linear relationship between standby load needs and monthly peak.[61] Mr. Pollock's assumption of this linear curve is based on the Bary Curve.[62] The Bary Curve measures the relationship between load factor and coincidence factor. The problem is that the Bary Curve is an example of an explicitly *non-linear* relationship. While Mr. Pollock is correct that there is a higher probability (i.e. positive relationship) that as the load factor increases the likelihood of the load occurring coincident with a system peak increases, simply using a daily rate as a proxy is way too simplistic, since it is a non-linear relationship [63]

44. ***Summary.*** Both standby charge proposals are fundamentally flawed and should not be approved. Energy+ should be required to implement the outcome of the C&I consolation, where a generic Ontario CRC methodology is to be determined.

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[59] TMMC Responses Clarification Interrogatories 2-VECC-7/8/9; Tr.2, p.83-85

[60] Transcript Vol .2, p.71s

[61] TMMC Responses Clarification Interrogatories 2-VECC-14.4

[62] *Ibid*

[63] Lawrence J. Vogt, *Electricity Pricing: Engineering Principles and Methodologies*, chapter 12.2

Cost Allocation

45. ***Background.*** Cost allocation is the process of allocating approved costs (i.e. revenue requirement) to the various customer classes. As the Board has said, "the primary criterion in developing the cost allocation methodology is to follow sound cost causality."[64] The nature of the exercise is a zero sum. Fewer costs allocated to one group of customers means more costs have to be allocated to others. This is clear from the updated bill impact summary of the various cost allocation scenarios that have been run throughout the proceeding.[65] This is why it is fundamental that the allocation of costs be fair and consistent for all customer classes. The same principles and rules should apply to allocating costs to every customer and rate class.

46. Cost allocation is primarily undertaken by the application of the Board's Cost Allocation Model ("CA Model"). The CA Model is released annually by Board Staff and reflects the current approved methodology.[66]

47. The CA Model allocates the cost of each USoA account to each rate class by various allocators depending on the nature of the asset or expense. Depending on the asset or expense that makes up the USoA account, either a customer count or a demand allocator is used. For example, most assets are allocated on the basis of 4NCP (non-coincident peak). This means for a given rate class, a USoA is allocated on the basis of the class' share of the sum of all customers average top 4 monthly non-coincident peak demands. This is known as the 'pooling method', and reflects that only rarely can specific assets or expense be specifically attributable to only one customer class with any precision. In addition, when direct allocation cannot be done, to better reflect cost causality USoA accounts (and sub-accounts) are grouped by function (primary, secondary, bulk etc.). [67]

48. ***Direct Allocation Principles.*** Board policy does allow, in limited circumstances, the direct allocation of certain costs or assets to a customer class where "a distributor should identify any

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[64] *Board Directions on Cost Allocation Methodology For Electricity Distributors* (EB-2005-0317 - Cost Allocation Review), September 29, 2006 ["Board Directions on Cost Allocation Methodology For Electricity Distributors"], p.3

[65] K1.6

[66] Ontario Energy Board Filing Requirements For Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications - Chapter 2 Cost of Service (July 12 2018), p.43-45

[67] Board Directions on Cost Allocation Methodology For Electricity Distributors, p.35

significantdistribution facilities that are dedicated exclusively to only one customer rate classification"[emphasis added].[68] In a direct allocation, those specific identifiable costs in a given USoA account are directly assigned to the relevant class. To ensure there is no double counting, the directly assigned amounts are removed from the pooled allocation to all other customers, and the allocation is also changed to remove the directly assigned customers' load. It also may be appropriate to directly assign zero costs to another USoA account that provides the same use or service as the directly assigned one.

49. With that limited exception, there is no general principle that can be considered the mirror of direct allocation, i.e. excluding the allocation of costs of a customer class that do not use a given asset. While it may seem intuitive that if a customer class does not use an asset or service whose costs are contained with a given USoA account, then none should be allocated to it. The problem is that ignores how the CA Model is designed. Since assets and expenses are pooled, they are allocated to customer classes using allocators that are not limited to customers who use that asset or expense. Those allocators include loads of all customers regardless of whether they use a given asset or not. While a customer class that does not use a given asset is allocated some of its costs and in can be said to be 'over-paying', it is also 'under-paying' for other assets that it does use. This is because the allocator in the CA Model is based on all loads, regardless of whether a customer uses or does not use the asset.

50. Much of the dispute in this proceeding is over which costs should or should not be directly allocated. Mr. Pollock has taken an extreme view of which costs should be allocated to Large Use, or a separate TMMC Class. While SEC recognizes direct allocation to TMMC is appropriate for certain assets and costs, it should be done in a fair and consistent manner.

51. ***Feeders.*** SEC submits that two feeders which serve TMMC should be directly allocated to the Large Use or a TMMC specific class.[69] Those assets are exclusively used by TMMC, and so meet the direct allocation requirements. Since TMMC has previously made capital contributions related to these feeders, it is fair to directly allocate those specific contributions as well.[70]

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[68] Board Directions on Cost Allocation Methodology For Electricity Distributors, p.30 ; K1.5, p.53

[69] Transcript Vol.1, p.144

[70] Energy+ Response to TC TMMC IR 1 Response to Technical Conference Question TMMC-1

52. ***Meters.*** Mr. Pollock has proposed that the meters used to serve TMMC be directly allocated. SEC agrees with Energy+ that doing so is not appropriate. First, using the Board's own language, it does not meet the requirement that the assets be "significant".[71] Second, every meter is unique to an individual customer. In theory, all meters could be directly assignable to individual customer classes. But Energy+ records the cost of meters by customer class like all other distributors, so any direct allocation of individual meters to customer classes would need to involve either a review of underlying work orders, or estimates.[72] There is no reason why a similar estimate cannot be done for all customers to estimate costs as was done for TMMC.

53. ***O&M Costs.*** Mr. Pollock has proposed that certain O&M costs related to the maintenance of the two exclusive feeders be directly allocated to it. Energy+ opposes this on the basis that these estimates have "a high margin for error"[73]. SEC agrees that these O&M costs should not be directly assigned due to the margin of error. Energy+ did not undertake a time study which would be needed to do a proper allocation of these costs.[74]

54. ***Underground Conduits.*** Mr. Pollock has excluded the cost of all underground facilities, including both conductors (Account #1845-4) and conduits (Account #1840-4).[75] If the Board agrees with the TMMC proposal for its own rate class, then excluding allocation of underground conductors is appropriate since it will have been directly allocated to overhead conductor (Account #1835-4) costs of its two dedicated feeders. This is a reasonable approach since a customer's primary service can only be provided by way of either an overhead or underground conductor. It is very different with respect to underground conduits (Account #1840-4) which are the support structure for underground conductors. Those should not be excluded because the mirror service, overhead poles (which are used to support overhead conductors) are not directly assignable to TMMC. They are

[71] Board Directions on Cost Allocation Methodology For Electricity Distributors, p.30 ; K1.5, p.53

[72] Transcript Vol.1, p.122-123

[73] Argument-in-Chief, para 60, citing, Tr.1, p.171-172

[74] *Ibid*

[75] See Pollock Report (Updated), Appendix JP-11

pooled assets used to serve other conductors that serve non-TMMC customers.[76] The CA Model does not allow allocation of underground and overhead assets on different bases.[77]

55. As Energy+ noted, "the costs of both overhead and underground facilities are allocated to all customer classes in accordance with the Board's CA Model without considering, on a customer-by-customer basis, exactly what types of assets are used to serve them".[78] SEC submits it is only appropriate to exclude an asset or expense, if a similar service is being directly allocated to the customer class. If the asset is being pooled, then excluding the similar asset will lead to a cross-subsidization from all other customers, since the demand allocators used for the allocation include loads from all customers, not just customers or customer classes who use the asset.

56. ***Bulk Costs.*** Energy+'s proposal is that all bulk facility (>50 KV) costs should be allocated to all customer classes, with the exception of embedded distributors.[79] Mr. Pollock's proposal goes further, as he believes it is appropriate to exclude the Large Use class (and the proposed TMMC class) from the allocation of bulk costs.[80]

57. Mr. Pollock's rationale for proposing to exclude the Large Use class from bulk costs is that neither TMMC nor the other large user are served from Energy+ bulk facilities (i.e. transformer station), since they are served directly from Hydro One's transformer stations. The costs of the transformation service, provided by Hydro One is recovered in the Retail Transmission Service Rates ("RTSR").

58. Similar to the issue of underground conduits, Mr. Pollock's approach would result in a cross-subsidy from all other Energy+ ratepayers to TMMC, since the costs recovered through RTSR are allocated to all customers based on the total load of all customers, regardless of which transformer station serves them. Mr. Pollock admitted he did not even look at RTSR costs in the context of his work in this proceeding.[81]

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[76] Transcript Vol.1, p.129

[77] Transcript Vol.1, p.187

[78] Argument-in-Chief, para. 63

[79] Response to Technical Conference Question VECC-7; Argument-in-Chief, p.20-21

[80] Transcript Vol.2, p.62

[81] Transcript Vol.2, p.65

59. SEC demonstrated the cross-subsidy during the oral hearing through the use of a simplified example.[82] To ensure there is no cross-subsidy, if the Board were to accept Mr. Pollock's approach of excluding bulk costs from the allocation to the Large Use class, then the Board must similarly make an adjustment to the allocation of costs included in the RTSR to remove the loads of customers served by Energy+ bulk facilities. This will lead to an increase in costs allocated through the RTSR to TMMC. Since it is likely impossible to determine which customers in which classes are served by Energy+ bulk facilities, making the necessary adjustment is not possible.

60. SEC submits Energy+ is correct to allocate all the bulk costs, similar to costs included in the RTSRs, on a pooled basis to all customer classes.

61. ***One or Two Large Use Classes.*** Mr. Pollock has proposed that TMMC be split into its own Large Use class, with the second large user making up the other Large Use class. SEC notes that if cost allocation is undertaken correctly, there should be no impact on any other customer class of the decision for one or two large use classes. For this reason SEC does not take a strong view on the issue.

62. SEC does note that Mr. Pollock has provided some evidence that explains how TMMC is in a sufficiently unique situation that may warrant its own Large Use class. At the same time, Energy+ has provided evidence regarding its concern with this approach, not only on its operations, but also a significant direct impact on the other Large Use customer.[83]

63. With respect to Mr. Pollock's proposal, while there are significant differences in how each large user is served, and material differences in their load profiles and operational characteristic, relative size of the two customers is not an appropriate reason for there to be two classes. Both are large users with loads above 5MW, and the nature of the CA Model already, through the various demand allocators, apportions costs to each.

[82] See K2.1, p.5

[83] See for example, Transcript Vol 1, p.20-21

Embedded Distributor Cost Allocation

64. A few days before the oral hearing began, the Board issued a decision which determined that the alternative methodology outlined in a VECC technical conference question for allocating costs to embedded distributors was out of scope. In the same decision the Board requested submissions from parties in final argument on how the issue should be adjudicated on a going forward basis. [84]

65. The concern that SEC has is that there is inconsistency regarding how host distributor costs are allocated to their embedded distributors.

66. SEC notes that the alternative methodology proposed in the VECC technical conference question, the allocation of costs to embedded distributors using the CA Model, is not a departure from Board policy. While it is correct that Energy+ in its previous cost of service application used a different methodology, it is that approach, using Appendix 2-Q to allocate costs, which differs from Board policy. Appendix 2-Q itself says that it is "[n]ot required if a Host Distributor has Embedded Distributor rate class, i.e. separate row on Sheet 11 of the RRWF".[85] This is consistent with the wording of the Board's Filing Requirements, which directs the use of Appendix 2-Q for host distributors who propose to bill their embedded distributions as if they were General Service class customers.[86]

67. SEC has reviewed the research conducted by VECC outlined in its Final Argument. VECC notes that it reviewed all cost of service proceedings over the last 3 years, with the exception of Energy+. VECC notes that no other host distributors allocated costs to their embedded distributor on the basis of Appendix 2-Q. Included in the list are *both Hydro One and BPI*, which are both also embedded distributors of Energy+. Hydro One neither uses Appendix 2-Q, nor has a separate rate class to allocate costs to its embedded distributors.

68. The Board should have a consistent treatment of the allocation of costs to embedded distributors on a going forward basis. If the Board's decision on scope in this proceeding is a signal

[84] Decision on Embedded Distributor Cost Allocation, March 4 2019, p.3

[85] Appendix 2-Q

[86] Filing Requirements For Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications - Chapter 2 Cost of Service, June 12 2018, p.46

that it is considering changing its policy regarding the cost allocation of embedded distributors, then it should undertake a policy consultation so that there is consistency in approach across distributors.

<u>Gross Load Billing</u>

69. Energy+ proposes to bill customers with LDG on the same basis that it is billed by the IESO for Line Connection Service Rate and Transformation Connection Service Rate. Energy+ is billed on a gross load basis for LDG facilities with a generator unit rating of 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation, applied on a gross load billing basis.[87]

70. There is a merit in aligning how Energy+ collects RTSR costs from its customers with how it is billed. This ensures there are no cross-subsidies between customers. Yet, SEC notes that the Board in its recent decision in EB-2017-0038, it commented, when approving the Settlement Agreement which resulted in the withdrawal of a similar request by Erie-Thames Powerlines that, "the OEB agrees that [gross load billing] is a complex matter that is best considered under a policy review."[88] This was similar to a comment made in a letter to all distributors *more than 3 years ago*. [89]

71. Unlike a standby charge, there is no on-going or announced review of the issue of gross load billing of RTSR, even though the board had previously stated that it would look at the issue in the (then) upcoming C&I Consultation.[90]

72. SEC is unsure of the expectations of the Board at this time on distributors applying for gross load billing, since it is not aware of any review or consultation on the issue. The consequences of not approving the proposal, is that TMMC's fair share of RTSR costs will continue to be subsidized by all other customer classes. This is especially unfair in the context of this proceeding, where through its expert TMMC is seeking a significant shifting of costs to other customer classes.

[87] Argument-in-Chief, para. 74

[88] *Decision and Rate Order*, (ETPL 2018 - EB-2017-0038), November 1 2018, p.6

[89] See Letter from OEB, Re: Billing for Customers with Load Displacement Generators, March 29 2016 <https://www.oeb.ca/oeb/_Documents/Documents/OEBltr_Gross_Load_Billing_Tx_20160329.pdf>

[90] *Ibid*

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

March 29, 2019

Original signed by

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Mark Rubenstein
Counsel to the School Energy Coalition

EB-2018-0028

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15 (Schedule B);

AND IN THE MATTER OF an application to the Ontario Energy Board by Energy+ Inc. pursuant to Section 78 of the *Ontario Energy Board Act* for approval of its proposed distribution rates and other charges, effective
January 1, 2019.

FINAL ARGUMENT OF THE

SCHOOL ENERGY COALITION

A. Overview

1. Energy+ Inc. ("Energy+") has filed an application for approval of distribution rates effective January 1, 2019.

2. Most of the application was settled by way of a Settlement Proposal filed with the Board on December 12 2018. A number of issues remained unsettled relating to the Energy+ proposal for an Advanced Capital Module ("ACM"), certain deferral and variance accounts, and all issues related to cost allocation and rate design, including the request to approve a standby charge.

3. This has been an unusually complicated proceeding for a distributor of Energy+'s size. The proceeding had multiple rounds of interrogatories, a technical conference, and the filing of both additional evidence from Energy+ and intervenor evidence from Toyota Motor Manufacturer Canada Inc. ("TMMC").

4. This is the final Argument of the School Energy Coalition ("SEC") on the unsettled issues.

B. Advanced Capital Module (Southworks Facility)

5. Energy+ seeks approval of an ACM for its proposed $8.1M Southworks facility, expected to go into-service in 2022.[1] The Southworks facility would house Energy+'s administrative staff, and is

[1] Updated Evidence, p.2

part of a larger Facilities Business Plan ("Facilities Plan") that includes a new shared operations centre with Brantford Power Inc. ("BPI"), the renovation of its existing Bishop Street facility, the sale of its current Dundas St. property, and the end of its lease for the Thompson St. facility.[2] Energy+ has brought forward the project as an ACM instead of as an ICM, as it wishes to have the regulatory certainty regarding its ability to recover costs before it expends the significant funds. [3]

6. SEC submits that the evidence demonstrates that the project meets the ACM requirements of materiality and need, but Energy+ has not met its onus to demonstrate that the Southworks facility is prudent. The Board should deny the ACM but allow Energy+ to reapply if it is able to bring forward evidence to demonstrate that the Southworks facility is the best option available for its proposed administrative offices.

7. ***Project.*** Energy+'s evidence is that due to challenges related to the age and condition of its various buildings, the merger with Brant County Power, and the operational needs of its staff, significant expansion and renovation of its facilities are needed. To determine what the best approach would be, it undertook a number of third-party assessments in 2013 to 2015 and landed on the current set of proposals which makes up its integrated Facilities Plan.[4]

8. One aspect of that Facilities Plan was the need for centralized and more appropriate administrative space to act as a head office in Cambridge.[5] The evidence was that Energy+ was approached by a third-party developer, who wanted Energy+ to act as the anchor tenant in a new mixed-use development which includes commercial shopping properties and two large condominium towers.[6] In return, Energy+ was given the ability to acquire a portion of an existing building for $1.[7] When the application was originally filed, the cost to renovate the building for its purposes was $5M,

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[2] Ex.2, p.25; Exhibit 2, Appendix N; Interrogatory Response 2-SEC-27b), Appendix

[3] Technical Conference Transcript, p.11

[4] Exhibit 2, Appendix N, p.1027-1029

[5] Exhibit 2, Appendix N, p.1025

[6] Transcript, Vol.1, p.32; Interrogatory Response 2-SEC-27b), Appendix, p.435;

[7] Transcript, Vol.1, p.58-59

with an in-service date of 2020.[8] By the late fall, the cost has already ballooned by 62% to $8.1M, and the project delayed until 2022.[9]

9. SEC submits that there are numerous concerns about the prudence of the proposed Southworks Facility.

10. ***Unreliable Class Estimate.*** There is little reason to have much faith in the accuracy of the updated forecast of $8.1M, considering the past history of the project. The new forecast is based on a Class C estimate, which has a range of accuracy of +/- 20% ($6.58M-$9.7M).[10] The problem is that the previous forecast of $5M, based on a Class D estimate, was entirely incorrect and the error was more than double the accuracy range of +/-30% at 62%.[11] In fact, when one looks at only the construction cost estimate, as opposed to other aspects of the broader project, the increase is even higher.[12] This is a very significant increase in costs that has not been adequately explained, and should give the Board little assurance of the reliability of the current forecast, which is only Class C.

11. ***No Analysis Undertaken to Demonstrate Southworks Was Best Option.*** Energy+ determined based on its analysis that the best option was a dedicated administration facility. Yet, it took no analysis to determine if the current proposal for the Southworks facility was the best option for a dedicated administrative facility. It did not retain the help of a real estate professional to look at other options for a purely administrative building, either to purchase or lease.[13] Mr. Miles, on behalf of Energy+, testified that they did not do this because a) there is not a lot of real estate in Cambridge, and b) they were going to tender out the material and construction costs to ensure the costs are prudent. [14]

12. Neither rationale is sufficient. First, Energy+ is not a real estate company, and in preparing to spend millions of dollars to purchase and construct a new building, it was incumbent upon them to

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[8] Transcript, Vol.1, p.56-57; Updated Evidence, p.2

[9] *Ibid*

[10] Transcript, Vol.1, p.65, 72-73

[11] Transcript, Vol.1, p. 73

[12] Transcript, Vol., p.72

[13] Transcript, Vol., p.49-50

[14] Ibid

do the necessary due diligence to determine that the specific site it purchased was the most cost effective solution. Without that information, not only does Board unableable make that assessment in assessing the application, but neither did Energy+ when it decided to go forward with Southworks facility. While having a purely administrative building may be prudent in the context of the overall Facility Plan, there is no evidence on the record to justify that the Southworks facility itself is the prudent option. Second, the fact that Energy+ will put the construction out for competitive bid is not relevant to the question of the prudence of the Southworks option. At best it is simply an indicator that the costs to construct the project, based on the specific site and design are reasonable, it reveals nothing about the prudence of the site and design itself.

13. ***Energy+ Costs Above Benchmark.*** Based on the forecast costs of the project, the cost per square foot appears to be significantly higher than other similar projects. In its evidence, Energy+ provided benchmarking information regarding the cost of its entire Facilities Plan, compared against new builds or purchase/renovations undertaken by other distributors.[15] The problem with Energy+'s analysis is that within its costs it includes the renovation of its existing Bishop Street facility. A renovation of an existing facility used for distribution services is a fraction of the cost of a new facility, and is entirely dissimilar to those of the comparator distributor projects that Energy+ selected. When that facility is removed, and only the Southworks and Garden Street facility are included, Energy+'s forecast costs per square foot are significantly *higher* than the comparators. Since the Garden St. facility is not before the Board at this time, and the benchmark facilities are all dual administrative and operations facilities, it is not clear why the total cost is so much higher, but it is a concern that warrants requiring further information from Energy+, before approving the cost consequences of the project.

14. In its Argument-in-Chief, Energy+ puts great emphasis on its comparative advantage when comparing square foot per FTE.[16] SEC accepts that on this metric, Energy+ is lower, but that only shows that the size of the property is more appropriate, not the cost of the property.

[15] Exhibit 2, p.1024; Updated Evidence, p.11-13

[16] Argument-in-Chief, para 40-41

	Energy + (Entire Facilities Plan)	Energy+ (Southworks & Garden St.)	Energy + (Southworks)	Waterloo North Hydro	InnPower	Milton Hydro	PUC Distribution Inc.
Year of Occupancy	2022/22/24	2020/22	2022	2011	2015	2015	2012
Function	Admin & Ops	Admin & Ops	Admin	Admin & Ops	Admin & Ops	Admin & Ops	Admin & Ops
Type	Purchase/ Refubish	Purchase/ Refubish	Purchase/ Refurbish	Custom Build	Custom Build	Purchase/ Refubish	New Build
Capital Cost	14,500,000	$12,500,000	$8,100,000	$26,682,000	$10,896,704	$12,524,798	$23,000,000
Square Footage	88,243	35,143	21,892	105,000	36,172	91,872	110,382
Capital Cost/Square Footage	*$164.32*	*$355.69*	*$370.00*	*$254.11*	*$301.25*	*$136.33*	*$208.37*
Source: Response to SEC TCQ-5							

15. ***Energy+ Did Not Select the Construction Management or Architectural Firm***. Energy+ did not select the architectural or the construction management firms, who are responsible for the design and the cost estimates, by way of a competitive procurement process. [17]In fact, it is not clear if Energy+ had any involvement in their selection. The evidence is that they were used, solely because they were used by the developer in the larger development process. Due to this, it is not clear whether their interest is entirely aligned with Energy+, as oppose to with the developer.

16. ***Summary.*** Energy+ has not met its onus to determine that the proposed Southworks project is prudent. The Board should deny the ACM on this basis. With that said, there is no evidence that the project is necessarily imprudent, and due to the need for some solution to its administrative space needs, Energy+ should be allowed to apply again once it has undertaken an appropriate verifiable assessment that the Sourthworks option is the most appropriate. Since Energy+ is already planning to bring forward a joint incremental capital module application with BPI for the proposed Garden St. facility[18], it can undertake the necessary work and file that additional evidence with that application. This would allow Energy+ to have a decision from the Board before much of the work is underway so as to still have certainty regarding the project.

[17] Transcript Vol. 1, p.57-58

[18] Settlement Proposal, December 12 2018, p.17:

> Energy+ also agrees to withdraw its request for 2020 Advanced Capital Module funding for its proposed Garden Avenue facility in Brantford, which will be a shared facility with Brantford Power Inc. Energy+ agrees with the supporting Parties noted below that it would be more efficient for the Board to consider the entire Garden Avenue facility at the same time and to reduce the possibility of inconsistent decisions. The supporting Parties noted below expect that Energy+ will submit an Incremental Capital Module request, together with a request to dispose the gain on sale of the Paris facility, concurrently with Brantford Power Inc.'s Incremental Capital Module application.

C. Deferral And Variance Accounts

OEB Cost Assessment

17. Energy+ seeks recovery of Account 1508 – OEB Cost Assessment Account of $174,000 for the balances attributable to the years 2016 and 2017.[19]

18. The OEB Cost Assessment account was established on a generic basis by the Board by letter dated February 9, 2016, in response to the revision of the methodology used to apportion its costs under section 26 of the *Ontario Energy Board Act*.[20] Since it was the Board's view that the new methodology "may result in material shifts in the allocation of costs", it created a generic variance account to capture the difference between the cost assessment amounts built into rates and the cost assessments that will result from the application of the new model.[21]

19. The creation of this generic account was not meant to ensure that all balances would be recoverable, no matter the individual magnitude for a given regulated entity. The Board's letter was clear that "regulated entities are reminded that, in the normal course, any disposition of deferral and variance account balances must meet any OEB default or company-specific materiality thresholds".[22] This interpretation has been subsequently confirmed by the Board.[23]

20. Energy+ confirmed that its annual materiality threshold is $250,000.[24] The principal balances for amounts in 2016 of $70,507 and 2017 of $99,102 are both well below the Energy+ materiality threshold.[25] On that basis, since the annual amounts are not material, the Board should deny clearance of the balances of this account for 2016 and 2017.

Monthly Billing

21. Energy+ is seeking recovery of a total of $416,346 for costs in 2016 and 2017 for the incremental costs related to the Board's requirement that all distributors move to monthly billing, for

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[19] Ex.9, p.30

[20] OEB Letter, Revisions to the Ontario Energy Board Cost Assessment Model, February 9, 2016 <https://www.oeb.ca/oeb/_Documents/Corporate/Letter_Notice_of_Change_to_CAM_20160209.pdf>

[21] *Ibid*

[22] *Ibid*, p.2

[23] See *Decision and Order* (EB- EB-2018-0105 – Union Gas Ltd), November 26 2018, p.11-13

[24] Transcript Vol.1, p.89; Ex.1, p.164

[25] Ex.9, p.30

the former Cambridge North Dumfries ("CND") service territory. In CND's 2015 IRM application, the Board approved the deferral account to record the incremental costs net the associated savings, such as improved cash flow and a reduction in bad debt.[26]

22. SEC does not take issue with the costs included in the account, only the calculation of the benefits. Energy+ has estimated the cash flow benefits related to the transition as the incremental interest increase that would have been generated from the increase in cash flow.[27] SEC disagrees with this approach.

23. As the Board is aware, for rate-making purposes, a distributors cash flow needs are funded by applying a percentage of an amount for working capital to the rate base where it earns its weighted average cost of capital.[28] The working capital amount is determined by applying a working capital percentage, which attempts to measure the net lag in expenses to revenues, to the distributor's OM&A, property taxes and cost of power .This may or may not be an accurate reflection of the working capital a given distributor actually does need to manage its cash flow, but it is how that cost is included in rates, including Energy+ [29]

24. SEC submits the appropriate way to measure the cash flow benefit of moving to monthly billing is to determine what the change in working capital would be compared to that built into the rates. This ensures the cash flow 'benefit' is calculated on a similar basis to cash flow 'costs'.

25. Complicating matters is that when asked to provide the working capital savings, Energy+ responded by stating that it "has not done a lead lag study or any other analysis to calculate any working capital savings from the former CND in 2017".[30] Since Energy+ has not done the analysis, SEC has attempted to estimate the impact on the revenue requirement of moving all former CND customers to monthly billing in late 2016. In its 2016 cost of service application, CND used the then

[26] *Decision and Rate Order* (EB-2015-0057 - CND), March 17 2016, see Schedule C

[27] Updated Evidence, p.29

[28] Transcript Vol.1, p.81; OEB Letter Re: Allowance for Working Capital for Electricity Distribution Rate Applications, June 3 2015; K.1.5, p.19

[29] Transcript Vol.1, p.81

[30] Interrogatory Response 9-SEC-42; K1.4, p.4

Board default value of 13%, to determine the working capital.[31] The problem with the 13% default value is the Board never provided a breakdown of how the amount was calculated.

26. To determine the impact, SEC has used the analysis the Board used in determining that the revised default value of the working capital allowance would be 7.5%[32]. Isolating the service lag/period which reflects the billing period calculation, if all customers were on bi-monthly billing versus monthly billing, that represents a 4.2% change in the total working capital allowance.[33] That number needs to be further adjusted to reflect the fact that only residential and some GS<50 customers were ever on bi-monthly billing.[34] Mr. Molon testified on behalf of Energy+ that the gross billings, for customers who transitioned to monthly billing, represented approximately 30% of the total amount billed.[35]

27. Based on this, SEC estimates the change in the working capital allowance related to the move to monthly billing to be approximately 1.26% of the working capital allowance. Considering that the CND 2014 revenue requirement included $1,489,594 for working capital based on 13% working capital allowance, a reduction of 9.6% (1.26%/13%) would result in an annual reduction of $143,001. Since the evidence is that customers began moving to monthly billing in late 2016, SEC has pro-rated the 2016 amount using the same time period as Energy+ (October-December). [36]

Monthly Billing Principal Balance		
	2016	**2017**
Energy+ Costs	$132,268	$365,718
Working Capital Savings	($35,750)	($143,001)
Recoverable Amount	***$96,518***	***$222,717***

28. SEC submits the appropriate recoverable amount is $96,518 for 2016 and $222,717 in 2017, plus the applicable DVA carrying charges.

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[31] Response to Technical Conference Question SEC-10(a); K1.5, p.11

[32] OEB Letter Re: Allowance for Working Capital for Electricity Distribution Rate Applications, June 3 2015, Appendix A; K.1.5, p.22

[33] K1.5, p.23

[34] Transcript Volume 1, p.87

[35] Transcript Volume 1, p.88

[36] Argument-in-Chief, para 111

LRAMVA

29. TMMC witnesses during the oral hearing appeared to question whether the Board Loss Revenue Adjustment Mechanism ("LRAM") was appropriate as it applied to it. Ms. Collis testified that TMMC found unfair that Energy+ lost revenue as a result of the TMMC's LDG facility it recovered from the rate class that was the cause.[37] For TMMC this means that for its LDG facility, the lost revenue would be recovered from the Large Use class or if successful, its own separate rate class. TMMC believes this is unfair.

30. SEC submits the Board should approve Energy+'s LRAM Variance Account ("LRAMVA") disposition methodology as proposed for two reasons. First, the policy on recover of the LRAMVA is well established and has been applied consistently to all distributors and all rate classes for years.[38] While SEC understands TMMC's complaint, the same could be said for all other customers and rate classes who engaged in conservation measures.[39] For example, schools have been early adopters in conservation and are disproportionately paying through the LRAM, the impact of conservation measures adopted by customers who are relatively late adopters. Second, it should be noted that LRAM only recovers the impact of approved conservation measures not built into distribution rates. It does not recover all other TMMC avoided costs due to its LDG facility, such as the much more significant commodity costs. TMMC is still significantly better off financially as a result of constructing its LDG facility.

D. Cost Allocation And Rate Design

Standby Charge

31. Energy+ has proposed the implementation of a standby charge for all customers in the GS>50, GS>1000, and Large Use rate classes who have load displacement generation ("LDG"). A standby charge is meant to capture the cost to Energy+, of being ready to provide a backup service when the load displacement generation is not generating, in full or in part. SEC submits that the proposed standby charge should not be approved at this time because, a) the Board is well advanced in a generic process to implement a Capacity Reserve Charge ("CRC") that would protect Energy+,

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[37] Tr.2, p.42-43
[38] See LRAMVA WorkForm
[39] TMMC's LDG Facility was undertaken as part of the IESO's Process and System Upgrade Initiative (Transcript Vol 1, p.24-25) which is considered a program eligible for LRAM. See *Report of the Ontario Energy Board Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs* (EB-2016-0182), May 19, 2016, p.5

b) the proposed structure would penalize customers who implement conservation and other efficiency measures, and c) a charge that requires negotiation between a customer and a distributor is only just and reasonable if the expectations are clear and the Board is the final arbitrator of the amount.

32. ***Energy+ Proposal.*** Energy+'s proposal is that the standby charge would be equal to the approved volumetric distribution rate and applied to the difference between the customer's monthly peak demand and that of a contracted demand level, called the contracted capacity.[40] The level of a contracted capacity for any given customer with load displacement generation would be determined by way of a negotiation between the customer and Energy+. While it may be styled as a negotiation, if the customer does not agree with Energy+, there is no neutral third-party who can make the determination. The dispute resolution process is simply an escalation within Energy+ management, and finally, the customer could seek non-binding advice from Board Staff.[41] There is also little guidance for how the contracted capacity should be determined. Energy+ has simply provided a long list of factors that should be considered.[42]

33. As the Board is aware, the matter of standby rates is something the Board is currently considering as part of its Rate Design for Commercial and Industrial Consultation ("C&I Consultation").[43] After years of consultation and discussion, Board Staff has recently released a report that proposes a CRC which would serve the same purpose as a standby charge. For most customers, the CRC would be determined on a more objective basis by charging the distribution volumetric rate on the technology specific capacity factor of the generators nameplate capacity.[44] If this approach is adopted by the Board in some form, then there would be no need for those customers to be required to negotiate with their distributor. For customers with demands over 5MW, there would be some room to negotiate the rate, depending on how they run the generator and recognition that they have this capability since they are "very sophisticated about their energy use".[45]

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[40] Exhibit 7, p.14-16

[41] 7-SEC-39b; K1.5, p.32

[42] 7-SEC-40(a); K1.5, p.32

[43] See EB-2015-0043

[44] Staff Report to the Board Rate Design for Commercial and Industrial Electricity Customers Rates to Support an Evolving Energy Sector (EB-2015-0043), February 21, 2019, p.41-43: K1.5, p.43-45

[45] *Ibid*, p.44-45; K1.5, p.46-47

34. The asymmetry of bargaining power between an individual GS>50, or even GS>1000 customer, and Energy+, is significant. Most customers do not understand the intricacies of an appropriate contracted capacity, based on their specific load profile and LDG type. If set at a level anywhere near the nameplate capacity[46], they will be overpaying and Energy+ will get a significant windfall.

35. Under the Energy+ approach, a customer will be required to pay the standby charge if the reduction in demand is below the contract capacity, even if it is caused in part by factors that have nothing to do with LDG. For example, if a customer with LDG also undertakes new energy efficiency or conservation measures, or simply reduces their use, they will be charged the standby rate for their actual peak demand below the contracted amount. For customers without LDG, they are not required to pay a standby charge or any other costs for reducing demand through conservation measures or by making consumption decisions.

36. ***Pollock Approach.*** TMMC's expert has proposed a very different approach to the design of a standby charge. Mr. Pollock proposes a two-party standby charge. First, a customer would be charged a contract volumetric rate that would be applied monthly to a negotiated contract amount, regardless of the actual use of any standby service. This cost would reflect what Mr. Pollock calls local facilities, which are similar to customer specific facilities.[47] Second, a customer would be charged a daily volumetric rate that would be applied to the incremental demand in the month when a generation unit is out of service. The daily rate could only ever be applied during the weekday (i.e. peak period of the month) and is designed to recover the shared facilities, assuming the outage lasted during all peak days in the month.[48]

37. There are significant problems with Mr. Pollock's proposed standby charge.

[46] By way of example, the Board Staff reports has set the capacity factor for solar generation at 10% of the name plate capacity to recognize that at a customer's monthly peak only a fraction for the nameplate capacity is used.

[47] Updated Written Evidence of Jeffrey Pollock (J. Pollock Incorporated) on behalf of Toyota Motor Manufacturing Canada Inc., February 15, 2019 ["Pollock Report (Updated)"], p.26

[48]Pollock Report (Updated), p.28,30

38. Mr. Pollock developed his proposal for TMMC.[49] He was only asked to determine how it would be applied to customers of all other rate classes during the interrogatory process.[50] As it became apparent during the oral hearing, there would be significant practical challenges for Energy+ to adopt his two-part rate methodology for other customers, whose LDG facilities are orders of magnitudes smaller than the TMMC facilities. For example, to determine when the daily volumetric rate should be applied, the information that Energy+ would "need to know is whether an outage occurred and what was the effect of that outage in terms of the additional load placed on the system, if any."[51] This admittedly "after-the-fact analysis" may be able to be done for a large LDG facility like TMMCs, but it is not clear how it could be done for potentially dozens of small scale facilities installed for net-metering. [52]

39. When asked how this analysis could be undertaken for a small scale rooftop solar facility, such as these that schools are increasingly undertaking, Mr. Pollock could not provide a good answer, and recognized "[t]hat would be challenging".[53] The problem is, for many customers who may install LDG facilities it could never be done. This is because what would be required under Mr. Pollock's proposal is for Energy+ to know at peak times how much output the generator is producing.

40. It is possible for TMMC since its LDG facility is separately metered.[54] For most customers with small scale LDG facilities that would attract a standby rate, their generation is not separately metered. All Energy+ knows is the customer's load *net* of generation.

41. A significant concern that SEC has with Mr. Pollock's methodology for the proposed standby charge is, what he considers local facilities versus shared costs for the purposes of designing the contract volumetric versus daily volumetric rate. In his initial evidence, Mr. Pollock used the directly assignable costs or costs that are allocated on a non-coincident peak basis as shared facilities for

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[49] Transcript Vol.2, p.70

[50] Interrogatory Response SEC-TMMC-3; Technical Conference Transcript, p.87; JTC.1.9

[51] Transcript Vol. 2, p.74-75

[52] *Ibid*

[53] Transcript Vol. 2, p.75

[54] Transcript Vol. 2, p.75

TMMC.[55] This changed in his updated evidence, where only the directly assigned costs, the feeders and meters, were considered local facilities.[56] For example, Mr. Pollock has treated poles, which are pooled asset class for all customers, as a shared facility for the purposes of TMMC, but a local facility for the GS>50 rate class.[57] The reason for this appears to be because Mr. Pollock has not done any analysis regarding which of Energy+ facilities should be considered local, as opposed to shared, for any other class but the proposed TMMC class.[58]

42. Mr. Pollock has been unable to provide a set of clear criteria that can be applied when allocating an asset or cost as either local or shared.[59] Since the contract volumetric rate, which is to recover local costs, is charged to customers regardless of their actual use of the standby service, the fewer costs categorized as local, the less the LDG customer would have to pay. Fairness between a utility and customers, and amongst customers', demands that workable and simple criteria be set out. As Mr. Pollock recognizes, more work would be needed. He testified that "you would have to do an analysis of the distribution system to further determine what portion, say, of the primary and secondary networks really are serving specific customers and therefore should be considered a local cost, as opposed to facilities that are more, you know, serving the nature of all customers, which would be a shared cost."[60]

43. SEC notes there are other issues regarding Mr. Pollock's approach. For example, the basis of the methodology behind the daily volumetric rate concept is that there is a linear relationship between standby load needs and monthly peak.[61] Mr. Pollock's assumption of this linear curve is based on the Bary Curve.[62] The Bary Curve measures the relationship between load factor and coincidence factor. The problem is that the Bary Curve is an example of an explicitly *non-linear* relationship. While Mr. Pollock is correct that there is a higher probability (i.e. positive relationship) that as the load factor increases the likelihood of the load occurring coincident with a system peak

[55] Written Evidence of Jeffrey Pollock (J. Pollock Incorporated) on behalf of Toyota Motor Manufacturing Canada Inc., September 27, 2018 ["Pollock Report (Original)"], p.50

[56] Pollock Report (Updated), p.27

[57] *Ibid.*, p.29

[58] TMMC Responses Clarification Interrogatories 2-VECC-15.1

[59] TMMC Responses Clarification Interrogatories 2-VECC-7/8/9; Tr.2, p.83-85

[60] Transcript Vol.2, p.71

[61] TMMC Responses Clarification Interrogatories 2-VECC-14.4

[62] *Ibid*

increases, simply using a daily rate as a proxy is way too simplistic, since it is a non-linear relationship [63]

44. ***Summary.*** Both standby charge proposals are fundamentally flawed and should not be approved. Energy+ should be required to implement the outcome of the C&I consolation, where a generic Ontario CRC methodology is to be determined.

Cost Allocation

45. ***Background.*** Cost allocation is the process of allocating approved costs (i.e. revenue requirement) to the various customer classes. As the Board has said, "the primary criterion in developing the cost allocation methodology is to follow sound cost causality."[64] The nature of the exercise is a zero sum. Fewer costs allocated to one group of customers means more costs have to be allocated to others. This is clear from the updated bill impact summary of the various cost allocation scenarios that have been run throughout the proceeding.[65] This is why it is fundamental that the allocation of costs be fair and consistent for all customer classes. The same principles and rules should apply to allocating costs to every customer and rate class.

46. Cost allocation is primarily undertaken by the application of the Board's Cost Allocation Model ("CA Model"). The CA Model is released annually by Board Staff and reflects the current approved methodology.[66]

47. The CA Model allocates the cost of each USoA account to each rate class by various allocators depending on the nature of the asset or expense. Depending on the asset or expense that makes up the USoA account, either a customer count or a demand allocator is used. For example, most assets are allocated on the basis of 4NCP (non-coincident peak). This means for a given rate class, a USoA is allocated on the basis of the class' share of the sum of all customers average top 4 monthly non-coincident peak demands. This is known as the 'pooling method', and reflects that only

[63] Lawrence J. Vogt, *Electricity Pricing: Engineering Principles and Methodologies*, chapter 12.2

[64] *Board Directions on Cost Allocation Methodology For Electricity Distributors* (EB-2005-0317 - Cost Allocation Review), September 29, 2006 ["Board Directions on Cost Allocation Methodology For Electricity Distributors"], p.3

[65] K1.6

[66] Ontario Energy Board Filing Requirements For Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications - Chapter 2 Cost of Service (July 12 2018), p.43-45

rarely can specific assets or expense be specifically attributable to only one customer class with any precision. In addition, when direct allocation cannot be done, to better reflect cost causality USoA accounts (and sub-accounts) are grouped by function (primary, secondary, bulk etc.). [67]

48. ***Direct Allocation Principles.*** Board policy does allow, in limited circumstances, the direct allocation of certain costs or assets to a customer class where "a distributor should identify any <u>significant</u> distribution facilities that are dedicated exclusively to only one customer rate classification"[emphasis added].[68] In a direct allocation, those specific identifiable costs in a given USoA account are directly assigned to the relevant class. To ensure there is no double counting, the directly assigned amounts are removed from the pooled allocation to all other customers, and the allocation is also changed to remove the directly assigned customers' load. It also may be appropriate to directly assign zero costs to another USoA account that provides the same use or service as the directly assigned one.

49. With that limited exception, there is no general principle that can be considered the mirror of direct allocation, i.e. excluding the allocation of costs of a customer class that do not use a given asset. While it may seem intuitive that if a customer class does not use an asset or service whose costs are contained with a given USoA account, then none should be allocated to it. The problem is that ignores how the CA Model is designed. Since assets and expenses are pooled, they are allocated to customer classes using allocators that are not limited to customers who use that asset or expense. Those allocators include loads of all customers regardless of whether they use a given asset or not. While a customer class that does not use a given asset is allocated some of its costs and in can be said to be 'over-paying', it is also 'under-paying' for other assets that it does use. This is because the allocator in the CA Model is based on all loads, regardless of whether a customer uses or does not use the asset.

50. Much of the dispute in this proceeding is over which costs should or should not be directly allocated. Mr. Pollock has taken an extreme view of which costs should be allocated to Large Use, or a separate TMMC Class. While SEC recognizes direct allocation to TMMC is appropriate for certain assets and costs, it should be done in a fair and consistent manner.

[67] Board Directions on Cost Allocation Methodology For Electricity Distributors, p.35

[68] Board Directions on Cost Allocation Methodology For Electricity Distributors, p.30 ; K1.5, p.53

51. ***Feeders.*** SEC submits that two feeders which serve TMMC should be directly allocated to the Large Use or a TMMC specific class.[69] Those assets are exclusively used by TMMC, and so meet the direct allocation requirements. Since TMMC has previously made capital contributions related to these feeders, it is fair to directly allocate those specific contributions as well.[70]

52. ***Meters.*** Mr. Pollock has proposed that the meters used to serve TMMC be directly allocated. SEC agrees with Energy+ that doing so is not appropriate. First, using the Board's own language, it does not meet the requirement that the assets be "significant".[71] Second, every meter is unique to an individual customer. In theory, all meters could be directly assignable to individual customer classes. But Energy+ records the cost of meters by customer class like all other distributors, so any direct allocation of individual meters to customer classes would need to involve either a review of underlying work orders, or estimates.[72] There is no reason why a similar estimate cannot be done for all customers to estimate costs as was done for TMMC.

53. ***O&M Costs.*** Mr. Pollock has proposed that certain O&M costs related to the maintenance of the two exclusive feeders be directly allocated to it. Energy+ opposes this on the basis that these estimates have "a high margin for error"[73]. SEC agrees that these O&M costs should not be directly assigned due to the margin of error. Energy+ did not undertake a time study which would be needed to do a proper allocation of these costs.[74]

54. ***Underground Conduits.*** Mr. Pollock has excluded the cost of all underground facilities, including both conductors (Account #1845-4) and conduits (Account #1840-4).[75] If the Board agrees with the TMMC proposal for its own rate class, then excluding allocation of underground conductors is appropriate since it will have been directly allocated to overhead conductor (Account #1835-4) costs of its two dedicated feeders. This is a reasonable approach since a customer's primary service can only be provided by way of either an overhead or underground conductor. It is very different

[69] Transcript Vol.1, p.144

[70] Energy+ Response to TC TMMC IR 1 Response to Technical Conference Question TMMC-1

[71] Board Directions on Cost Allocation Methodology For Electricity Distributors, p.30 ; K1.5, p.53

[72] Transcript Vol.1, p.122-123

[73] Argument-in-Chief, para 60, citing, Tr.1, p.171-172

[74] *Ibid*

[75] See Pollock Report (Updated), Appendix JP-11

with respect to underground conduits (Account #1840-4) which are the support structure for underground conductors. Those should not be excluded because the mirror service, overhead poles (which are used to support overhead conductors) are not directly assignable to TMMC. They are pooled assets used to serve other conductors that serve non-TMMC customers.[76] The CA Model does not allow allocation of underground and overhead assets on different bases.[77]

55. As Energy+ noted, "the costs of both overhead and underground facilities are allocated to all customer classes in accordance with the Board's CA Model without considering, on a customer-by-customer basis, exactly what types of assets are used to serve them".[78] SEC submits it is only appropriate to exclude an asset or expense, if a similar service is being directly allocated to the customer class. If the asset is being pooled, then excluding the similar asset will lead to a cross-subsidization from all other customers, since the demand allocators used for the allocation include loads from all customers, not just customers or customer classes who use the asset.

56. ***Bulk Costs.*** Energy+'s proposal is that all bulk facility (>50 KV) costs should be allocated to all customer classes, with the exception of embedded distributors.[79] Mr. Pollock's proposal goes further, as he believes it is appropriate to exclude the Large Use class (and the proposed TMMC class) from the allocation of bulk costs.[80]

57. Mr. Pollock's rationale for proposing to exclude the Large Use class from bulk costs is that neither TMMC nor the other large user are served from Energy+ bulk facilities (i.e. transformer station), since they are served directly from Hydro One's transformer stations. The costs of the transformation service, provided by Hydro One is recovered in the Retail Transmission Service Rates ("RTSR").

58. Similar to the issue of underground conduits, Mr. Pollock's approach would result in a cross-subsidy from all other Energy+ ratepayers to TMMC, since the costs recovered through RTSR are allocated to all customers based on the total load of all customers, regardless of which transformer

[76] Transcript Vol.1, p.129

[77] Transcript Vol.1, p.187

[78] Argument-in-Chief, para. 63

[79] Response to Technical Conference Question VECC-7; Argument-in-Chief, p.20-21

[80] Transcript Vol.2, p.62

station serves them. Mr. Pollock admitted he did not even look at RTSR costs in the context of his work in this proceeding.[81]

59. SEC demonstrated the cross-subsidy during the oral hearing through the use of a simplified example.[82] To ensure there is no cross-subsidy, if the Board were to accept Mr. Pollock's approach of excluding bulk costs from the allocation to the Large Use class, then the Board must similarly make an adjustment to the allocation of costs included in the RTSR to remove the loads of customers served by Energy+ bulk facilities. This will lead to an increase in costs allocated through the RTSR to TMMC. Since it is likely impossible to determine which customers in which classes are served by Energy+ bulk facilities, making the necessary adjustment is not possible.

60. SEC submits Energy+ is correct to allocate all the bulk costs, similar to costs included in the RTSRs, on a pooled basis to all customer classes.

61. ***One or Two Large Use Classes.*** Mr. Pollock has proposed that TMMC be split into its own Large Use class, with the second large user making up the other Large Use class. SEC notes that if cost allocation is undertaken correctly, there should be no impact on any other customer class of the decision for one or two large use classes. For this reason SEC does not take a strong view on the issue.

62. SEC does note that Mr. Pollock has provided some evidence that explains how TMMC is in a sufficiently unique situation that may warrant its own Large Use class. At the same time, Energy+ has provided evidence regarding its concern with this approach, not only on its operations, but also a significant direct impact on the other Large Use customer.[83]

63. With respect to Mr. Pollock's proposal, while there are significant differences in how each large user is served, and material differences in their load profiles and operational characteristic, relative size of the two customers is not an appropriate reason for there to be two classes. Both are large users with loads above 5MW, and the nature of the CA Model already, through the various demand allocators, apportions costs to each.

[81] Transcript Vol.2, p.65

[82] See K2.1, p.5

[83] See for example, Transcript Vol. 1, p.20-21

Embedded Distributor Cost Allocation

64. A few days before the oral hearing began, the Board issued a decision which determined that the alternative methodology outlined in a VECC technical conference question for allocating costs to embedded distributors was out of scope. In the same decision the Board requested submissions from parties in final argument on how the issue should be adjudicated on a going forward basis. [84]

65. The concern that SEC has is that there is inconsistency regarding how host distributor costs are allocated to their embedded distributors.

66. SEC notes that the alternative methodology proposed in the VECC technical conference question, the allocation of costs to embedded distributors using the CA Model, is not a departure from Board policy. While it is correct that Energy+ in its previous cost of service application used a different methodology, it is that approach, using Appendix 2-Q to allocate costs, which differs from Board policy. Appendix 2-Q itself says that it is "[n]ot required if a Host Distributor has Embedded Distributor rate class, i.e. separate row on Sheet 11 of the RRWF".[85] This is consistent with the wording of the Board's Filing Requirements, which directs the use of Appendix 2-Q for host distributors who propose to bill their embedded distributions as if they were General Service class customers.[86]

67. SEC has reviewed the research conducted by VECC outlined in its Final Argument. VECC notes that it reviewed all cost of service proceedings over the last 3 years, with the exception of Energy+. VECC notes that no other host distributors allocated costs to their embedded distributor on the basis of Appendix 2-Q. Included in the list are *both Hydro One and BPI*, which are both also embedded distributors of Energy+. Hydro One neither uses Appendix 2-Q, nor has a separate rate class to allocate costs to its embedded distributors.

68. The Board should have a consistent treatment of the allocation of costs to embedded distributors on a going forward basis. If the Board's decision on scope in this proceeding is a signal

[84] *Decision on Embedded Distributor Cost Allocation*, March 4 2019, p.3

[85] Appendix 2-Q

[86] Filing Requirements For Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications - Chapter 2 Cost of Service, June 12 2018, p.46

that it is considering changing its policy regarding the cost allocation of embedded distributors, then it should undertake a policy consultation so that there is consistency in approach across distributors.

Gross Load Billing

69. Energy+ proposes to bill customers with LDG on the same basis that it is billed by the IESO for Line Connection Service Rate and Transformation Connection Service Rate. Energy+ is billed on a gross load basis for LDG facilities with a generator unit rating of 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation, applied on a gross load billing basis.[87]

70. There is a merit in aligning how Energy+ collects RTSR costs from its customers with how it is billed. This ensures there are no cross-subsidies between customers. Yet, SEC notes that the Board in its recent decision in EB-2017-0038, it commented, when approving the Settlement Agreement which resulted in the withdrawal of a similar request by Erie-Thames Powerlines that, "the OEB agrees that [gross load billing] is a complex matter that is best considered under a policy review."[88] This was similar to a comment made in a letter to all distributors *more than 3 years ago*. [89]

71. Unlike a standby charge, there is no on-going or announced review of the issue of gross load billing of RTSR, even though the board had previously stated that it would look at the issue in the (then) upcoming C&I Consultation.[90]

72. SEC is unsure of the expectations of the Board at this time on distributors applying for gross load billing, since it is not aware of any review or consultation on the issue. The consequences of not approving the proposal, is that TMMC's fair share of RTSR costs will continue to be subsidized by all other customer classes. This is especially unfair in the context of this proceeding, where through its expert TMMC is seeking a significant shifting of costs to other customer classes.

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[87] Argument-in-Chief, para. 74

[88] *Decision and Rate Order*, (ETPL 2018 - EB-2017-0038), November 1 2018, p.6

[89] See Letter from OEB, Re: Billing for Customers with Load Displacement Generators, March 29 2016 <http://www.oeb.ca/oeb/_Documents/Documents/OEBltr_Gross_Load_Billing_Tx_20160329.pdf>

[90] *Ibid*

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

March 29, 2019

Original signed by

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